Excerpts from Article 5.5. Marine Terminal Oil Pipelines

§2560 Purpose, Applicability, and Date of Implementation.

(a) Unless otherwise specified in these regulations, all of the provisions of these regulations become effective on September 1, 1998.

(b) The purpose of the regulations in Title 2, Division 3, Chapter 1, Article 5.5 of the California Code of Regulations is to provide the best achievable protection of the public health and safety and of the environment by using the best achievable technology in providing for marine terminal oil pipeline integrity.

(c) The provisions of Article 5.5 apply only to pipelines that are within or a part of marine terminals and are used to transfer oil either:

(1) Within the marine terminal; or

(2) To or from tank vessels or barges.

(d) The provisions of Article 5.5 do not apply to any pipelines:

(1) That are within or part of marine terminals and are isolated and disconnected from any pipeline or manifold which can be used to transfer oil within the marine terminal or to and from tank vessels and barges; or

(2) That are used exclusively to transport oil that are subject to the jurisdiction of the State Fire Marshal; or

(3) That are part of a tank vessel or barge.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2561 Definitions.

Unless the context otherwise requires, the following definitions shall govern the construction of this Article:

(a) "Class I pipeline" means any pipeline or portion thereof which does not meet the criteria specified for a Class II pipeline.

(b) (1) "Class II pipeline" means either of the following:

(A) Any pipeline or portion thereof which has experienced two or more reportable leaks due to corrosion or defect in the prior three years. Leaks experienced during an SLPT shall not be counted as a leak for the purpose of classification of pipelines as Class II pipelines.

For purposes of this definition, a leak which is traceable to an external force, but for which corrosion is partly responsible, shall be deemed caused by corrosion.

(B) Any pipeline or pipeline system a part of which extends over marine waters or wetlands and does not have any form of permanently installed effective containment located between the pipeline and the water surface or wetland over its entire exposed length over the water or wetlands.

(2) Each pipeline which has been classified as a Class II pipeline under subsection (b)(1)(A) of this section shall retain its classification as a Class II pipeline, until five years pass without a reportable leak due to corrosion or defect on that pipeline. After five years pass without a reportable leak, such Class II pipeline may be reclassified as a Class I pipeline following its next scheduled SLPT required by 2 CCR Section 2564(c)(3).

(3) For the purpose of classification of pipelines as Class II pipelines under subsection (b)(1)(A) of this section, all reportable leaks that have occurred due to corrosion or defect in the three years prior to the effective date of these regulations shall be taken into account in making that determination.

(4) For the purpose of reclassification of Class II pipelines as Class I pipelines under subsection (b)(2) of this section, any period of time without having a reportable leak shall commence from a date five years prior to the effective date of this regulation.

(c) "Component" means any part of a pipeline or pipeline system which may be subjected to pump pressure or liquid gravitational pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures.

(d) "Defect" means manufacturing or construction defects.

(e) "Division" means the Marine Facilities Division of the California State Lands Commission.

(f) "Division Chief" means the Chief of the Marine Facilities Division or any employee of the Division authorized by the Chief to act on his behalf.

(g) "Leak" or "reportable leak" means every unintentional liquid leak. A ?reportable leak? does not include an unintentional leak from a gasket, gland or sealing material at a pump, valve, elbow, tee, flange or closure, which has been stopped by immediate tightening of bolts or any similar prompt corrective action.

(h) "Marine terminal" means a facility, other than a vessel, located on or adjacent to marine waters in California and used for transferring oil to or from tank vessels or barges. The term references all parts of the facility including, but not limited to, structures, equipment and appurtenances thereto used or capable of being used to transfer oil to or from tank vessels or barges. For the purpose of this article, a marine terminal includes all piping not integrally connected to a tank facility.

(i) "Maximum allowable operating pressure" or “MAOP” means the highest safe operating pressure at any point in a pipeline system during normal flow or static conditions.

(j) "Oil" means any kind of petroleum, liquid hydrocarbons, or petroleum products or any fraction or residues therefrom, including, but not limited to, crude oil, bunker fuel, gasoline, diesel fuel, aviation fuel, oil sludge, oil refuse, oil mixed with waste, and liquid distillates from unprocessed natural gas.

(k) "Operator" when used in connection with marine terminals, pipelines, or facilities, means any person or entity which owns, has an ownership interest in, leases, rents, operates, participates in the operation of or uses that terminal, pipeline, or facility. "Operator" does not include any entity which owns the land underlying the terminal or the terminal itself, where the entity is not involved in the operations of the terminal.

(l) "Person" means any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

(m) "Pipe" or "line pipe" means a tube, usually cylindrical, through which oil flows from one point to another.

(n) "Pipeline or pipeline system" means a marine terminal pipeline through which oil moves within a marine terminal or between a marine terminal and a tank vessel or barge, including, but not limited to, line pipe, valves, other appurtenances connected to line pipe, fabricated assemblies associated with pumping units, and delivery stations and fabricated assemblies therein.

(o) “Standard Cathodic Protection System” or “SCPS” means an external corrosion control system used on underground or submerged metallic piping systems that is in conformance with and meets the criteria of the National Association of Corrosion Engineers (NACE) Standard RPO 169-92, Item No. 53002, revised April 1992; published by NACE, P.O. Box 218340, Houston, Texas 77218-8340.

(p) "State Fire Marshal" means the person, and any representative of the person, appointed by the Governor pursuant to Section 13101 of the Health and Safety Code.

(q) “Static Liquid Pressure Test" or “SLPT” means the application of internal pressure above the normal or maximum operating pressure to a pipeline or a segment of pipeline, under no-flow conditions, for a fixed period of time, utilizing a liquid test medium. For the purpose of these regulations, the liquid test medium used may be either water or a liquid hydrocarbon with a flash point greater than 140^{o} Fahrenheit. In circumstances where any other liquid medium is to be used for a SLPT, the operator shall petition the Division Chief using the procedures outlined in 2 CCR Section 2564(h).

(r) "Tank facility" means any one or combination of above ground storage tanks, including any piping which is integral to the tank, which contains crude oil or its fractions and which is used by a single business entity at a single location or site. A pipe is integrally related to an above ground storage tank if the pipe is connected to the tank and meets any of the following:

(1) The pipe is within the dike or containment area;

(2) The pipe is connected to the first flange or valve after the piping exits the containment area; or

(3) The pipe is connected to the first flange or valve on the exterior of the tank, if state or federal law does not require a containment area.

(s) "Transfer pipeline" or "transfer pipeline system" means a pipeline that is within or a part of a marine terminal. A transfer pipeline does not include a pipeline that is subject to the jurisdiction of the State Fire Marshal.

(t) "Wetlands" means streams, channels, lakes, reservoirs, bays, estuaries, lagoons, marshes, and the lands underlying and adjoining such waters, whether permanently or intermittently submerged, to the extent that such waters support and contain significant fish, wildlife, recreational, aesthetic, or scientific resources.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8750, 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2562 Notification and Reporting of Pipeline Incidents.

(a) The operator of any marine terminal at which there occurs a rupture, explosion or fire involving a transfer pipeline, including, but not limited to, a transfer pipeline system undergoing testing, shall notify the California Office of Emergency Services of the incident as soon as possible, but in no event later than twenty-four (24) hours after the incident.

(b) Within 30 days following any pipeline incident specified in subsection (a) of this section, the operator shall forward an incident report to the local area Division field office. The report shall include at a minimum;

(1) The date and time of the pipeline incident;

(2) The location and identity of the pipeline;

(3) The product in the pipeline at the time of the incident;

(4) The cause or causes of the incident; and

(5) Any remedial action taken to restore the integrity of the pipeline.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2563 Design and Construction.

(a) Any repairs, alterations or modifications to existing transfer pipeline systems shall meet the design and construction criteria specified in Subparts C and D of Part 195 of Title 49 of the Code of Federal Regulations.

(b) Every new transfer pipeline installed after these regulations become effective shall be designed and constructed in accordance with Subparts C and D of Part 195 of Title 49 of the Code of Federal Regulations.

(c) Each component of a pipeline which is exposed to the atmosphere shall be coated with material suitable for protecting the component from atmospheric corrosion.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2564 Schedule for Static Liquid Pressure Testing.

(a) No operator may operate any pipeline or pipeline system governed by this Article unless it has successfully completed an SLPT as specified in Section 2565, in accordance with the schedules prescribed in this section.

(b) This subsection (b) applies only to Class I Pipelines.

(1) Every newly installed pipeline or pipeline system shall have undergone a complete and successful SLPT prior to being used for any transfer of oil.

Subsequent SLPTs shall be conducted at the appropriate intervals prescribed in subsection (b)(3) of this section.

(2) Every existing pipeline or pipeline system which has any segment relocated or replaced shall undergo a complete and successful SLPT after completion of relocation or replacement and prior to being used for any transfer of oil. Subsequent SLPTs shall be conducted at the appropriate intervals prescribed in subsection (b)(3) of this section. The SLPT requirements of this subsection need not apply to cases where a component other than pipe is being replaced or added to the pipeline system and the manufacturer certifies that either:

(A) The component was successfully tested with an SLPT at the factory where it was manufactured or at the operator's facility; or

(B) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was successfully tested with an SLPT at the factory.

(3) Every pipeline or pipeline system shall be subjected to an SLPT within five (5) years of the date of its initial SLPT prescribed in subsection (b)(1) of this section. Subsequent SLPTs shall be carried out in accordance with the following schedule:

(A) For pipelines that do not have an SCPS and are buried or submerged either partially or wholly, at succeeding intervals not exceeding three year cycles from the date of test carried out under subsection (b)(3) of this section;

(B) For pipelines that have an SCPS and are buried or submerged either partially or wholly, at succeeding intervals not exceeding five year cycles from the date of test carried out under subsection (b)(3) of this section; and

(C) For pipelines or segments of pipelines situated entirely above the ground or water, at succeeding intervals not exceeding five year cycles from the date of test carried out under subsection (b)(3) of this section.

(c) This subsection (c) applies only to Class II Pipelines.

(1) Every newly installed pipeline or pipeline system shall undergo a complete and successful SLPT prior to being used for any transfer of oil. Subsequent SLPTs shall be conducted at the appropriate intervals prescribed in subsection (c)(3) of this section.

(2) Every pipeline or pipeline system which has been classified as a Class II pipeline under subsection (b)(1)(A) of Section 2561, shall undergo a complete and successful SLPT after being classified as a Class II pipeline and prior to being used for any transfer of oil. Subsequent SLPTs shall be conducted at the appropriate intervals prescribed in subsection (c)(3) of this section.

(3) In addition to the SLPTs required by either subsections (c)(1) or (2) of this section, subsequent SLPTs shall be conducted at the following intervals:

(A) For pipelines or pipeline systems that do not have an SCPS and are buried or submerged either partially or wholly, at succeeding intervals not exceeding one year cycles from the date of tests conducted under either subsections (c)(1) or (2) of this section, whichever is appropriate.

(B) For pipelines or pipeline systems that have an SCPS and are buried or submerged either partially or wholly, at intervals not exceeding three year cycles from the date of tests conducted under either subsections (c)(1) or (2) of this section, whichever is appropriate.

(C) For pipelines or segments of pipelines situated entirely above the ground or water, at succeeding intervals not exceeding three year cycles from the date of test carried out under either subsections (c)(1) or (2) of this section, whichever is appropriate.

(d) Each operator shall report any pipeline or segment thereof which meets the criteria of Class II pipeline to the local area Division field office within 30 days following the date the pipeline or portion thereof first meets the criteria as a Class II pipeline. Any pipeline determined to meet the criteria as a Class II pipeline which has not been so reported by the operator to the Division shall be deemed to have been a Class II pipeline on the date determined by the Division. The Division may determine that the period during which a Class II pipeline must have no reportable leaks in order to be reclassified as a Class I pipeline under 2561(b)(2) does not begin until the required notice is given. Any operator failing to submit such notification report as required shall, as in the case of any violation of any provision of this article, be subject to enforcement actions prescribed under 8670.57 through 8670.69.6 of the Government Code.

(e) Notwithstanding the requirements of subsection (c) of this section and subject to the approval of the Division Chief, an operator may implement an alternative method to assure the integrity of a segment of pipeline classified as Class II. When this alternative method has been implemented to the satisfaction of the Division Chief, the pipeline may be classified as a Class I pipeline.

(f) Alternative test methods, including, but not limited to, inspection by instrumented internal inspection devices, may be approved by the Division Chief on an individual basis. In approving an alternative to an SLPT, the Division Chief may require that the alternative test be conducted more frequently than the testing schedules specified in subsections (b) and (c) of this section.

(g) Notwithstanding the testing schedules specified in subsections (b) through (f) of this section, and in the event that the reported test results on a particular pipeline subject to this Article do not provide sufficient information as required by 2 CCR Section 2567(b), to the Division Chief to determine whether the affected pipeline could be the source of a discharge of oil or pose a threat to public health and safety or the environment, the Division Chief may require the terminal operator either:

(1) To provide any extra information to substantiate that a successful SLPT has been conducted; or

(2) To undergo an SLPT or any other non-destructive test or inspection.

(h) An operator may request that the Division Chief authorize the use of a test medium other than water or liquid hydrocarbon with a flash point greater than 140^{o} Fahrenheit. Such request must be submitted in writing at least 10 working days prior to beginning the SLPT. Such an alternative may be authorized where the Division Chief deems that it would provide a reasonably equivalent or better means of testing and that there will be no detriment to the public health, safety and the environment.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2565 Static Liquid Pressure Testing.

(a) Each transfer pipeline system and mechanical loading arm must not leak when undergoing an SLPT of at least 125 percent of the maximum allowable operating pressure.

(b) The pressure tests required by this section shall be conducted in accordance with Part 195 of Title 49 of the Code of Federal Regulations, except that an additional four-hour leak test under Section 195.303 of Title 49 of the Code of Federal Regulations shall not be required.

(c) A deadweight gauge capable of measuring to one-pound-per-square-inch (psi) increments shall be used during each pressure test. The deadweight gauge shall be calibrated to a standard directly traceable to the National Institute of Standards and Technology at least once every two years and shall have a valid Certificate of Traceability.

(1) Deadweight pressure readings shall be taken at least once each hour during the test.

(2) A pressure recording device shall continuously record the pipeline pressure versus time during the test. The pressure recording device shall be calibrated prior to every test.

(d) Test Temperature Data.

(1) Where circumstances permit, test temperature data shall be recorded as prescribed in the following subsections (d)(1)(A), (B) and (C):

(A) A temperature recording device shall continuously record the internal test medium temperature versus time during the test. The temperature recording device shall be calibrated prior to every test and have a range suitable for anticipated temperatures.

(B) The ambient air temperature shall be recorded at the same interval the deadweight pressure readings are taken.

(C) The pipe wall temperature shall be recorded at the same interval the deadweight pressure readings are taken.

(2) In circumstances where the test temperature data cannot be recorded as required by subsection (d)(1) of this section, temperature measuring devices shall be placed so as to provide representative sample temperatures of test medium, ambient air and pipe wall.

(e) Where different sections of a pipeline or pipeline system are located in considerably different environments (e.g., in the open air or below ground or water), the temperature of each segment in each environment shall be monitored separately. For the purposes of pressure compensation calculations due to temperature variations, each segment's temperature in its respective environment shall be used. The total pipeline or pipeline system temperature change shall be determined by adding the temperature change of each segment and prorating the segment's length to the total pipeline length or pipeline system length. Alternatively, each segment in its respective environment may be treated as a separate pipeline under test and the compensated pressure variations due to each segment's temperature variations may be added to arrive at the system pressure variation.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2566 Notification Prior to Testing; Observation of Tests.

(a) Notwithstanding any other statutory notification requirements, each operator shall notify the local area Division field office at least three working days prior to conducting any SLPT. The notification shall include all of the following information:

(1) The name, address, and telephone number of the operator.

(2) The specific location of the pipeline section to be tested and the location of the test equipment.

(3) The date and time the test is to be conducted: and

(4) The name and telephone number of the person responsible for certification of the test results.

(b) In the event that the date or time of a proposed SLPT is to be changed, the operator shall, as soon as is practicable, notify the local area Division field office of the rescheduled date and time of such SLPT.

(c) If, due to unforeseen circumstances, an unscheduled SLPT has to be conducted as soon as possible and within a period of three working days, the operator shall notify the local area Division field office as soon as it is practicable to do so, but in any case prior to commencement of the SLPT.

(d) Staff of the Division may observe any test conducted pursuant to this Article.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2567 Static Liquid Pressure Testing; Witnessing of Tests and Certification of Results; Test Result Reports.

(a) Witnessing of SLPTs.

Any SLPT required by this Article shall be witnessed by either:

(1) A person or persons who are registered on the current list of persons approved to witness testing activities of the State Fire Marshal; or

(2) A person or persons who are certified by the terminal operator as having, at a minimum, the necessary experience and qualifications to witness SLPTs to ensure that they are effectively carried out.

(b) Certification of SLPT Results.

Any SLPT required by this Article shall have its test results certified by either:

(1) A person who is registered on the current list of persons approved to certify test results of the State Fire Marshal; or

(2) A person who is certified by the terminal operator as having, at a minimum, the necessary experience and qualifications to certify SLPT results and current valid Authorized Inspector certification under any one or more of the following programs:

(A) The American Petroleum Institute's API 570, Piping Inspection Code, Appendix B-Inspector Certification;

(B) The American Petroleum Institute's API 510, Pressure Vessel Inspection Code, Appendix B-API Authorized Pressure Vessel Inspector Certification;

(C) The National Board of Boiler and Pressure Vessel Inspectors National Board Commissioned Inspector program NB-215, Revised October 24, 1995, 1055 Crupper Avenue, Columbus, Ohio 43229-1183; or

(D) A California State accredited program for qualification for a Certificate of Competency as Authorized Inspector of Boiler and Pressure vessels under 8 CCR **7**79.

(c) Records of certified test results shall be maintained by the terminal operator for a period of at least ten (10) years following completion of testing. Each test record shall include at a minimum, all of the following information:

(1) The date of the test;

(2) A description of the pipeline or pipeline segment tested including, but not limited to, a map of suitable scale showing the route of the pipeline; and

(3) The results of the test, including, but not limited to, calculations made to adjust for changes in volume due to temperature, pressure and elevation changes.

(d) Test results of any SLPT shall be subject to review by Division staff. When requested, the terminal operator shall provide the certified test results of any SLPT to the Division.

(e) Staff of the Division shall not supervise, control or otherwise direct the testing.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2568 Leak Prevention and Detection.

All Class II pipelines shall be provided with either a leak detection system or systems which meet the requirements of Section 2569, or be included in a preventative maintenance program which meets the requirements of Section 2570.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2569 Leak Detection System or Systems.

(a) Operators may meet the requirements of providing a leak detection system or systems by any of the following:

(1) Instrumentation with the capability of detecting a transfer pipeline leak equal to two percent (2%) of the maximum design flow rate within five minutes;

(2) Completely containing the entire circumference of the pipeline provided that a leak can be detected within fifteen minutes;

(3) For transfer operations which do not involve the use of hoses, conducting a pressure test of the pipeline acceptable to the Division Chief immediately before any oil transfer; or

(4) A combination of the above strategies.

(b) The operation of any leak detection system or systems provided under this section shall be described in the terminal's operations manual required by Section 2385 of Title 2, Division 3, Chapter 1, Article 5 of the California Code of Regulations.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2570 Preventative Maintenance Program.

(a) A preventative maintenance program must ensure the continued operational reliability of any pipeline or pipeline system affecting quality, safety and pollution prevention. The program shall, at a minimum, include all applicable requirements and guidelines prescribed in API 570, Piping Inspection Code - Inspection, Repair, Alteration and Rerating of In-service Piping Systems, First Edition, June 1993, published by the American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 2005.

(b) Inspection and Testing Requirements for Pipelines Included in a Preventative Maintenance Program.

(1) For pipelines which are buried or submerged either partially or wholly the following shall be carried out:

(A) Either annual SCPS inspections per API 570 guidelines and triennial SLPTs as prescribed in 2 CCR Section 2564(c)(3)(B) for pipelines fitted with SCPS, or annual SLPTs as prescribed in 2 CCR Section 2564(c)(3)(A) for pipelines not provided with SCPS, whichever is appropriate; and

(B) An inspection program for emergency shut-off and isolation valves that control the flow of oil which shall, at a minimum, include that the stems of all such valves be stroked at least once a year.

(2) For pipelines which are situated entirely above the ground or water, the following shall be carried out:

(A) Triennial SLPTs as prescribed in 2 CCR Section 2564(c)(3)(C) and triennial pipewall thickness measurement inspections per API 570 guidelines; and

(B) An inspection program for emergency shut-off and isolation valves that control the flow of oil which shall, at a minimum, include that the stems of all such valves be stroked at least once a year.

(3) For any pipeline which is above ground for substantially all of its length, but which has a relatively short portion below ground buried beneath one or more berms or roads, the operator may petition the Division Chief for the application of testing and inspection requirements for the entire pipeline as prescribed under 2 CCR Section 2570(b)(2). Such petitions shall follow the procedures outlined in 2571.

(c) Any preventative maintenance program shall also include procedures to review proposed changes in operations, including materials transferred, to evaluate potential impacts on pipeline integrity.

(d) Terminal operators shall validate that the preventative maintenance program is being effectively carried out by maintaining documentation which includes, at a minimum, all of the following:

(1) The procedures for carrying out the preventative maintenance program in conformance with the requirements of API 570;

(2) Dates of inspections and tests;

(3) Inspections and test data evaluation including analyses, pipewall thickness measurements and remaining life calculations;

(4) The terminal management's internal audits of the program, including descriptions of controls and corrections for non-conformities;

(5) Repairs, alterations and rerating of piping systems; and

(6) Any other information pertinent to the integrity of pipelines.

(e) Every terminal operator shall provide to the Division access at any time to any documentation required under subsection (d) of this section.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code.

§2571 Modifications or Alternatives.

(a) Petitions for Modifications or Alternatives.

(1) Any person subject to these regulations may submit a petition to the Division Chief for modifications or alternatives to the requirements of Article 5.5 as applied to the petitioner.

(2) All petitions for modifications or alternatives must be submitted in writing. A petition may be in any form, but it must contain all data and information necessary to evaluate its merits.

(b) Response to Petitions.

The Division Chief shall respond in writing to any petition for modifications or alternatives within 30 days of receipt of the petition.

(c) Approval of Modifications or Alternatives.

(1) The Division Chief may approve any proposed modifications or alternatives to the requirements of Article 5.5 if he or she determines that the proposed modifications or alternatives will fulfill the purpose of these regulations as outlined in subsection (b) of Section 2560 of this Article.

(2) If the Division Chief approves any proposed modification or alternatives under this section, a letter of approval shall be issued to the petitioner setting forth the findings upon which the approval is based.

(3) The Division Chief may withdraw the letter of approval of any modifications or alternative requirements at any time if he or she finds that the person or persons subject to these regulations have not complied with the approved modified or alternative requirements.

(4) Withdrawal of a letter of approval under this section shall be effective upon receipt by the petitioner of written notification of the withdrawal from the Division Chief.

Authority: Sections 8755 and 8757, Public Resources Code.

Reference: Sections 8751, 8752, 8755, 8756 and 8757, Public Resources Code